inconsistent with other benchmarks, in part due to an incorrect interpretation of NREL's ATB forecast methodology. I also take issue with the system mix between fixed-tilt and single-axis trackers and find that Duke's figures are outdated compared to the movement of the market.

Several of Duke's portfolios rely on new SMR and pumped hydro capacity. While acknowledging the challenges of permitting, developing, and constructing these assets, Duke also included documentation that directly contradicts its timeline projections. If Duke is correct on how long these projects will take to develop, it cannot also be correct on when they will be in service.

The impact of these changes in input assumptions and modeling methodologies will likely produce portfolios that retire coal sooner, add less natural gas, and add more solar and storage, particularly early in the planning horizon. Each of these reduces risk of an updated portfolio, reducing substantial regulatory risk associated with the ongoing operation of coal plants and blunting the impact of a potential increase in fossil fuel costs.

A. The Recent ITC Extension Materially Changes Solar and Solar Plus Storage Economics in the Near Term

Q46. WHAT IS THE FEDERAL ITC AND HOW DOES IT IMPACT PROJECT ECONOMICS?

A46. The federal ITC is a tax credit that developers can use to offset a portion of the qualified capital costs of a solar project. It applies to both stand-alone solar projects and solar-plus- storage projects, with the ITC applying to both solar and storage capital costs in the latter. In a typical financing structure, developers will partner with "tax equity" providers that have significant federal tax liability and thus the ability to utilize the tax credits. These tax equity investors will contribute a portion of the up-front cost of the project in exchange for the right to claim the tax credits. This financing method supports the development of assets such as solar PV in which most of the life-cycle costs are incurred up front and that have very low operating costs over the life of the project. The ITC has been a critical driver of solar deployment over the past decade.[59]

Q47. HOW HAS THE ITC LEVEL CHANGED IN RECENT YEARS?

A47. Until recently, the federal ITC was in the process of stepping down. It had been equal to 30% of the eligible project costs for projects commenced in 2019, 26% for 2020, 22% for 2021, and was on schedule to fall to 10% for non-residential projects and 0% for residential projects in 2022 and beyond. To be eligible for any credit in excess of 10% a project also had to be placed in service within four years and also by December 31, 2023. These values were codified in the then-current statute and were thus properly assumed in Duke's IRP modeling completed in summer 2020.

However, Congress passed legislation in December 2020 that extended the stepdown by two years. Now, projects begun by December 31, 2022 will enjoy the 26% credit and those started by December 31, 2023 will receive the 22% credit. Congress also extended the "safe harbor" provisions of the tax credit, which allows developers to "lock in" the ITC for up to four years based on the commencement of construction of the project as long as they are in service by December 31, 2025. This means that a project that begins in December 2022 can lock in the 26% credit as long as it is placed into service before January 1, 2026.[60]

Q48. DOES THIS EXTENSION MAKE A SIZABLE IMPACT ON THE ECONOMICS OF SOLAR PROJECTS?

A48. Yes. The extension of two years is very meaningful. Figure 3 below compares the two schedules showing Duke's assumptions and the current law. The two-year extension provides a relatively modest incremental tax benefit of 4% in 2021, but a much larger 16% and 12% increase in 2022 and 2023, respectively. Further, the drop-dead date for placing a project in

[59] For more information, please see https://www.seia.org/initiatives/solar-investment-tax-credit-itc.
[60] Projects that incur 5% of total costs or have started "physical work of a significant nature" can claim to have "commenced construction" and thus can claim "safe harbor" for the ITC for the entire project cost. For more information, see https://www.seia.org/initiatives/commence-construction-guidance.

service while still being able to safe harbor ITCs higher than 10% has also been pushed back two years. This is critical period in Duke's IRP as it continues to ramp up renewable energy.

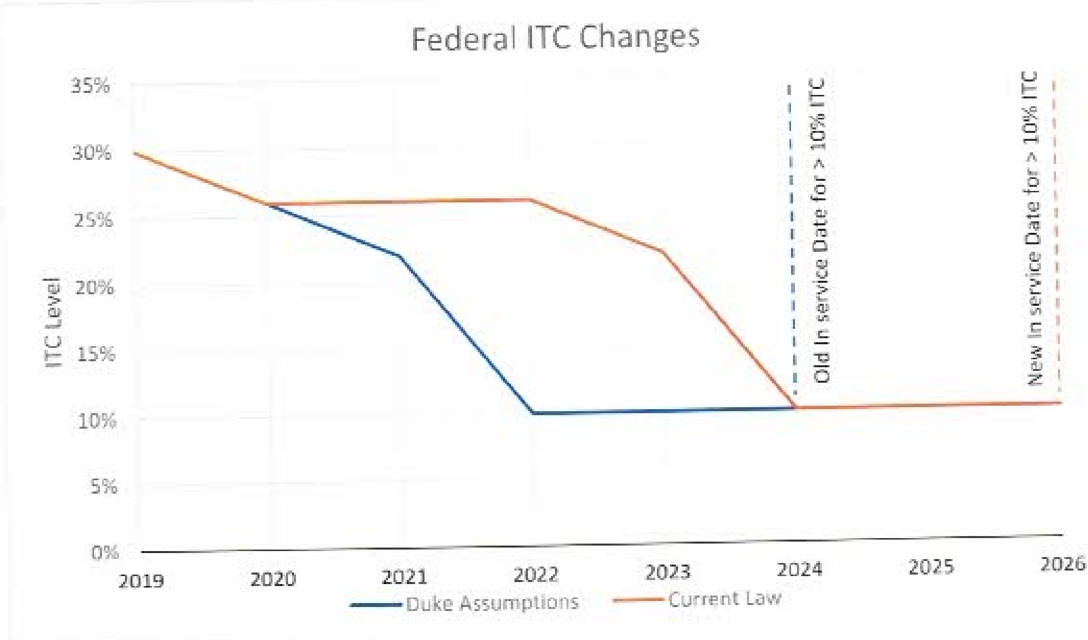

Figure 3 - Federal ITC Changes

Q49. HOW LARGE OF AN IMPACT DOES THE ITC EXTENSION HAVE ON SOLAR ECONOMICS?

A49. Enabling developers to claim a tax credit equal to an incremental 4%, 16%, and 12% of the total capital cost of the project will have a meaningful impact on the economics of new solar and solar plus storage projects. NREL's ATB workpaper calculates the levelized cost of energy ("LCOE") for several locations. While cities in Duke's territories are not specifically modeled, ATB does include data for Kansas City which has similar insolation as Duke's North Carolina and South Carolina territories.

Table 3 below shows the LCOE using NREL ATB's Advanced cost parameters under the old and new ITC paradigm for Kansas City. While neither the production figures nor the financial assumptions are the same as assumptions that Duke or other solar developers would use in South Carolina, the figures serve as a good proxy for the magnitude of impact that the ITC change may have on Duke's modeled results. The percentage reduction in the LCOE of the project is nearly equivalent to the incremental ITC benefit. For projects coming online in 2022 and 2023, there could be a $3-4 / MWh reduction in levelized cost, pushing solar costs into the low-$20s per MWh. This change will make solar even more competitive to new generation, much less with the running costs of existing generation. But capturing these cost reductions will only be possible by increasing solar and solar plus storage deployments in the early portion of Duke's planning horizon.

LCOE ($/MWh)	2020	2021	2022	2023	2024
Duke ITC Assumptions	$24.62	$24.82	$27.07	$25.91	$24.73
Current Law	$24.62	$23.69	$22.74	$22.80	$24.73
$ Delta	$0.00	($1.13)	($4.33)	($3.11)	$0.00
% Delta	0.0%	-4.5%	-16.0%	-12.0%	0.0%

Table 3 - LCOE Under Duke ITC Assumptions and Current Law

Given the four-year safe harbor provisions, it is possible to push out the online date of projects while still capturing a higher ITC level. Developers can capture the higher ITC by ordering adaptable interconnection equipment that it applies to various RFPs. As such, as long as Duke continues with annual RFPs on schedule, developers should be able to lock in the higher ITC for RFPs out to 2023. This would allow equipment placed into service in 2025 while still capturing the higher ITC.

Q50. GIVEN THIS EXTENSION WAS NOT IMPLEMENTED UNTIL AFTER DUKE FILED ITS IRP, HOW DO YOU RECOMMEND PROCEEDING?

A50. Duke was correct to model the existing statute when filing the IRP. However, Act 62 requires the Commission to determine whether a plan was the most reasonable and prudent "as of the time the plan is reviewed."[61] Duke's IRP is still being reviewed, and failing to incorporate the sizable change in law in its modeling would be contrary to Act 62's provisions. I recommend that the Commission direct Duke to update its modeling to reflect the new reality of the federal ITC extension and safe harbor provisions.

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[61] S.C. Code Ann. § 58-37-40(C)(2).

B. *Duke's Solar PV Capital Cost Assumptions Must Incorporate the ITC Extension but are Otherwise Reasonable*

Q51. How did Duke develop its renewable energy capital cost assumptions?

A51. Duke relied on capital cost assumptions for offshore wind, solar, and energy storage from Navigant for the years 2020 through 2029.[62] For 2030 forward, Duke escalated costs based on the capital cost increase index from the 2020 EIA AEO.[63] The resulting blended capital cost forecast reflects Carolina-specific factors such as labor costs and land rental while capturing the national-level longer-term cost reduction trends as solar technology evolves.

Q52. How does Duke's forecast compare to NREL ATB's forecast?

A52. Because Duke's forecast utilizes regional-specific data rather than NREL ATB's general nationwide averages, Duke's near-term forecast reflects the lower costs associated with doing business in the Carolinas. Directionally, Duke's forecast represents a downward step of roughly 20% from the NREL ATB Moderate scenario in 2020. Annual cost reductions are shallower than the NREL ATB Advanced scenario from 2020 through 2030, before aligning with the ATB Advanced scenario in 2030 and beyond. The resulting forecast is shown in Figure 4 below.

[62] Exhibit KL-3.
[63] DEP IRP Report at 322.

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Q53. WHAT IS YOUR VIEW OF THIS FORECAST?

A53. On balance, I believe it is reasonable, although these values must be updated to incorporate the ITC extension. It properly adjusts for local construction and land rent cost factors and shows an overall cost reduction trajectory that, while not as aggressive as the NREL ATB Advanced scenario, does reasonably mirror the ATB Moderate scenario. I recommend that Duke monitor the evolution of solar capital costs and revisit them frequently as the industry has more often than not seen faster cost reductions than anticipated. If in the future costs are falling faster than currently anticipated, Duke could readily update its forecast.

C. *Duke's Solar Fixed O&M Costs are Too High*

Q54. WHAT WAS THE VALUE AND SOURCE FOR DUKE'S SOLAR FIXED O&M COSTS?

A54. Duke used a value of $[redacted] kW-year based on an "internal PV O&M model." This was held constant through the analysis period.[64]

Q55. HOW DOES THIS VALUE COMPARE TO THE NREL ATB FIGURES?

[64] Exhibit KL-3.

A55. It is relatively higher than the capital cost forecast, and unlike that metric, Duke does not project a decline in prices over time in the fixed O&M cost category. The NREL ATB Moderate and Advance cases have fixed O&M costs for 2020 of $16.65 and $16.48 / kW-year, respectively, falling steadily to $15.24 and $14.11/ kW-year, respectively, in 2025. Duke's 2020 figure is roughly 12% lower than NREL ATB's, a notable divergence from its capital cost adjustment. By 2025, Duke's figure has not changed while the NREL ATB has fallen 8.5% and 14.5% even after accounting for inflation.

Figure 5 below shows the original and adjusted NREL ATB values along with Duke's forecast. The adjustment applies the same average 19% discount to the fixed O&M costs as was projected on the capital costs. By comparison, Duke's projection for fixed O&M begins and stays too high. **BEGIN CONFIDENTIAL**

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Q56. ARE THERE INCENTIVES FOR THE SOLAR INDUSTRY TO DRIVE REDUCTIONS IN FIXED O&M COSTS?

A56. Absolutely. As capital costs fall, fixed O&M costs become a higher proportion of the lifecycle costs of a solar plant. Solar is a competitive industry seeking to apply new technologies and data analytics to proactively and predictively anticipate outages to minimize system downtime. Companies that can bid lower cost O&M costs will be able to win competitive procurements, and penalty provisions in PPA documents ensure that operators will hold up their end of the bargain lest face financial penalties. The NREL ATB forecast recognizes these factors and price in a decline over time.

Q57. WHAT DO YOU RECOMMEND WITH REGARDS TO DUKE'S FIXED O&M COSTS?

A57. I recommend that Duke model lower costs to mirror the discount from the NREL ATB that is used in the Company's capital cost forecast. I further recommend that it assume a price decline at least as aggressive as the NREL ATB Moderate scenario to reflect the innovation occurring the in O&M space.

D. *Duke's Energy Storage Cost and Operational Assumptions are Inappropriate*

Q58. HOW DID DUKE CONSTRUCT ITS ENERGY STORAGE COSTS?

A58. Duke relied on a third-party to produce its energy storage cost estimate rather than relying on one of several publicly available benchmarks. The Company admits that its prices "appear higher than published numbers" but claims this is due to differing assumptions.[65] Specifically, Duke claims that its higher prices are impacted by:

- Using a 20% depth of discharge ("DoD") limit
- Historic DEC/DEP interconnection costs
- Higher software and control costs
- More expensive HVAC and fire suppression equipment
- High integration costs due to the Company's lack of experience with energy storage[66]

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[65] DEC IRP Report at 341.
[66] DEC IRP Report Appendix H.

Despite calculating higher initial prices than other benchmarks, Duke does forecast a 34% price decrease between 2020 and 2029.[67] However, other benchmarks also project steep cost declines and thus Duke's costs continue to be above other estimates through 2029.

Q59. How does Duke's topline battery cost estimate compare to other benchmarks or RFP results?

A59. Duke claims that a standalone 50 MW / 200 MWh battery connected at the transmission level and online in 2021 would cost [redacted] kW.[68] This figure is compared to other benchmarks in Table 4 below.

	Capital Cost ($/kW)			Fixed O&M ($/kW-year)		
Online Date	2021	2025	2029	2021	2025	2029
Duke	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NREL ATB Advance	$1,204	$926	$800	$30.10	$23.16	$20.00
NREL ATB Moderate	$1,469	$1,194	$1,121	$36.74	$29.84	$28.03
Lazard v 5.0 (2019)[69]	$898 - $1,874 (2019)					
Lazard v 6.0 (2020)[70]	$752 - $1,401 (2020)					
Santee Cooper RFI	$1,324 (2022)					

Table 4 - Energy Storage Cost Comparison

Q60. Duke claims that other benchmarks "likely only calculate the cost of the battery based on the rated energy of the battery" rather than adjusting for DoD and degradation. Is this accurate?

A60. No. Duke stated that "NREL benchmarked costs against publicly available 3rd party data. If another source did not includes [sic] costs for DoD, NREL did not add additional costs in their benchmarking."[71] While it is true that NREL noted "a number of challenges inherent in

[67] DEC IRP Report at 341.
[68] Exhibit KL-3.
[69] Lazard's Levelized Cost of Storage Analysis – Version 5.0. November 2019. Available at https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
[70] Lazard's Levelized Cost of Storage Analysis – Version 6.0. November 2020. Available at https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf.
[71] Exhibit KL-7, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-14, attachment NCSEA DR 3-14_BatteryCostComparison).

developing cost and performance projections based on published values", its methodology insulates the final cost projection from this issue:[72]

> To develop cost projections, storage costs were normalized to their 2019 value such that each projection started with a value of 1 in 2019. We chose to use normalized costs rather than absolute costs because systems were not always clearly defined in the publications. For example, it is not clear if a system is more expensive because it is more efficient and has a longer lifetime, or if the authors simply anticipate higher system costs. With the normalized method, many of the difference [sic] matter to a lesser degree. Additionally, as will be shown in the results section, the 2019 benchmark cost that we have chosen for our current cost of storage is lower than nearly all the 2019 costs for projections published in 2017. By using normalized costs, we can more easily use these 2017 projections to inform cost reductions from our lower initial point.[73]

NREL's approach uses third-party data to develop an average cost decline over time and applies that to a benchmark 2019 price of $380 / kWh to create its projections.[74] As long as the individual studies in the third-party data maintained internally consistent assumptions (an entirely reasonable assumption), the specific DoD and degradation assumptions of the individual research reports are less important.

Duke is correct that Lazard's 2019 energy storage report assumed 100% DoD and did not account for degradation. However, Lazard's 2020 energy storage analysis corrected these issues, assuming a 90% DoD assumption and oversizing batteries by 10% to allow for degradation over time.[75] These results produced the more robust results shown in Table 4 above.

Q61. HOW DOES DUKE ACCOUNT FOR BATTERY DEGRADATION OVER TIME?

A61. Batteries degrade with usage. To maintain a minimum performance threshold, one can either oversize the battery at the beginning or augment the battery capacity over time to counteract the degradation. In the overbuild approach, one may install 120 MWh of battery packs in a battery rated at 100 MWh. This would allow for 20 MWh of degradation over the lifetime and

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[72] Cost Projections for Utility-Scale Battery Storage: 2020 Update, NREL June 2020. ("NREL 2020 Update") Available at https://www.nrel.gov/docs/fy20osti/75385.pdf
[73] *Id.* at 3.
[74] NREL 2020 Update at 5.
[75] Lazard v6.0 at 4.

still enable the battery to charge and discharge 100 MWh. Under an augmentation strategy, one would install a 102 MWh battery and add roughly 2 MWh of new capacity each year to counteract the degradation of the original capacity. This would also allow the battery to charge and discharge 100 MWh through the life of the project.

Duke approaches this issue differently for standalone storage and for solar plus storage installations. For standalone storage, Duke utilizes an annual replenishment strategy.[76] The annual replenishment cost for the standalone storage is in addition to (and slightly higher than) its annual fixed O&M costs and explains why Duke's estimates are so much higher than NRELs. By contrast, NREL allocates all operating costs to the fixed O&M bucket and uses the higher of the fixed O&M estimates from third parties, thus "in essence assum[ing] that battery performance has been guaranteed over the lifetime, such that operating the battery does not incur any costs to the battery operator."[77] It is unclear why Duke has total fixed O&M costs so much higher than NREL's given that NREL's costs already include everything required for turnkey operation of the project, including the impacts of degradation.

For solar plus storage installations, Duke assumes the lifetime of the battery is equal to the 30-year life of the solar asset, overbuilds the initial battery, and makes one change at year 15 to functionally rebuild the battery.[78] The overbuild is substantial. For a 75 MW solar PV, 20 MW / 80 MWh ("usable") battery configuration with a 20% DoD limitation, Duke first assumes that 100 MWh of storage is required for 80 MWh of "usable" storage. Then, to account for degradation, Duke further assumes a 43% overbuild ratio to allow the battery to degrade for 15 years at roughly 2.4% per year before being overhauled. It also assumes a very high ILR of 1.6, adding further to the total costs of the project.[79]

[76] DEC IRP Report at 340.
[77] NREL 2020 Update at 10.
[78] Exhibit KL-8, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 5-2).
[79] Exhibit KL-3.

Q62. IS DUKE'S APPROACH TO BATTERY DEGRADATION IN SOLAR PLUS STORAGE PROJECTS LIKELY TO BE A LEAST-COST APPROACH?

A62. No. Energy storage costs are declining rapidly, a fact that Duke itself readily admits and assumes. Under this case, it is inexplicable that Duke would overbuild its solar plus storage batteries upfront by a total of 79% (143 MWh for an 80 MWh "usable" battery) at today's higher costs. The much more rational approach would be to replace energy storage packs as needed on an annual basis to capture the benefit of the cost declines, as it did in its standalone storage approach and as is done in NREL ATB.

Failing to do so greatly exaggerates the cost of storage within the solar plus storage project. This can be seen by comparing the projected cost of two 10 MW / 40 MWh standalone batteries to the cost of the 20 MW / 80 MWh storage asset in the solar plus storage project. The 2020 total cost for the standalone battery project is $[redacted] but the corresponding total cost of battery portion of the solar plus storage project is $[redacted] more than 16% higher. This cost differential was explained by Duke to be related to the choice of managing battery degradation over time.

Q63. ASIDE FROM THE IRRATIONALITY OF THIS APPROACH, DOES DUKE'S CALCULATION OF THE BATTERY REPLACEMENT COST HAVE FLAWS?

A63. Yes. In its calculation for the levelized fixed cost of replacing a battery midway through the 30-year life, Duke's calculation erroneously assumes that 100% of the battery pack must be replaced. Its formula further assumes the incorrect date for the battery replacement. In the calculation for a 2020 solar plus storage battery replacement (due to be done in 2035 for a system installed in 2020), Duke calculates the cost of replacing 100% of the battery pack, 50% of the power electrics, 15% of the system integration cost, and 5% of the site installation costs. However, these costs are taken from 2032, not 2035, shorting the expected cost reduction for the replacement capacity by three years.

Further, the calculation assumes that 100% of the battery must be replaced. Recall that Duke had overbuilt an 80 MWh "usable" battery to 100 MWh to account for DoD, and then further overbuild by 43% to 143 MWh to allow for degradation. After fifteen years of degradation, the battery should still be providing 100 MWh of capacity. For Duke to completely scrap this battery at zero residual value, despite its sizable remaining capacity, is inconsistent with its own assumptions. At a minimum, Duke should account for some residual value from this battery. More appropriately, it should only replace the 43 MWh of overbuild needed to return the battery to the original overinflated capacity with some allowance for incremental capacity to account for the higher likelihood of battery failure past year 15. If the Commission allows Duke to use this approach, it should at least require it to use the proper year for the replacement capacity calculation and require some level of credit for the residual value of the battery.

Q64. ARE THERE OTHER INCONSISTENCIES BETWEEN DUKE'S ENERGY STORAGE ASSUMPTIONS FOR STANDALONE STORAGE AND SOLAR PLUS STORAGE PROJECTS?

A64. Yes. Duke appears to be using a different capital cost estimate for its battery packs in a solar plus storage projects than in a standalone storage projects. For standalone storage projects, battery packs in 2020 are projected to cost [redacted]/ kWh of storage. This value is consistent across all sizes and durations of standalone projects. However, for the 20 MW / 80 MWh solar plus storage project, the battery pack is assumed to cost [redacted] kWh if measured on a "usable" basis (i.e. 80 MWh), [redacted] kWh if measured after a DoD adjustment (i.e. 100 MWh), or [redacted] / kWh if based on the actual storage amount installed (i.e. 143 MWh).

Considering that Duke plans to initially install the 143 MWh battery for this project, it appears the lowest cost estimate is the most appropriate. However, that begs the question as to why the battery pack cost would be so much lower in this configuration than for a standalone storage project, particularly considering the degradation strategies and other costs such as power electronics are independent from this cost. Duke's internally inconsistent projections, all of which have been marked confidential, lend further weight to using a publicly available benchmark such as NREL's ATB.

Q65. What do you recommend with regard to battery storage costs?

A65. Duke's cost estimates are substantially higher than other benchmarks and recent RFI results. While Duke claims the difference is largely due to assumptions on DoD and replenishment approaches, it erred in interpreting NREL's ATB battery cost methodology. Further, the Commission already ruled on this issue in the DESC IRP case, finding that DESC similarly overinflated its storage costs and directed it to remodel its IRP using NREL ATB's Advanced scenario.[80] I recommend the Commission find similarly in this case and require that Duke base its battery costs on NREL's ATB Advanced scenario, recognize that battery pack degradation is already accounted for in NREL's ATB fixed O&M cost and should not be used to artificially inflate the size of a modeled battery, and require Duke to use consistent costs for batteries in standalone storage and solar plus storage projects unless it can justify differential in cost due to operational expectations.

Q66. What assumptions did Duke use for storage duration in its ELCC modeling?

A66. Duke modeled energy storage at two-, four-, and six-hour durations in its 2020 ELCC Study.[81] However, it decided to model only four- and six-hour duration batteries in its IRP, stating that "[t]wo-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak."[82]

Q67. Do two-hour batteries provide useful capacity during winter and summer peak load hours?

[80] DESC IRP Order at 50.
[81] DEC IRP Report at 345.
[82] DEC IRP Report at 349.

A67. Yes, they do. Duke included several analyses that show that while two-hour batteries tend to produce lower capacity contribution levels than 4- or 6-hour batteries, they can contribute significantly to winter and summer peak loads. Figure 6 below is the ELCC curve of various battery sizes for DEC and DEP.[83] The two-hour battery (in blue) is somewhat lower than the four-hour (orange) and six-hour (green) lines, but it maintains more than 85% of its capacity value up to about 1,100 MW and 70% of its capacity value up to about 2,500 MW of storage.

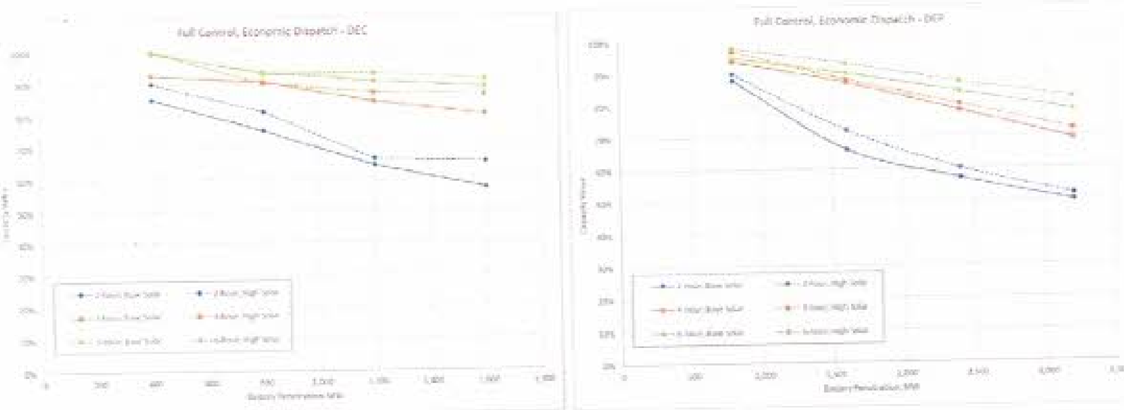

Figure 6 - DEP and DEP Battery ELCC

Considering that battery packs represent a substantial share of an energy storage system's cost, allowing a limited quantity of less expensive two-hour batteries can help defer the need for other capacity at a lower price.

Q68. WHAT IS YOUR RESPONSE TO DUKE'S CLAIM THAT TWO -HOUR BATTERIES "GENERALLY PERFORM THE SAME FUNCTION AS DSM PROGRAMS"?

A68. I disagree. DSM programs typically have limits on how often they can be activated, and even if they did not, participant fatigue could diminish the response after multiple consecutive calls. By contrast, two-hour batteries are independent of business or behavioral decisions and can reliably perform every single day for years on end.

Q69. WHAT DO YOU RECOMMEND REGARDING MODELED BATTERY DURATION?

[83] Figure H-4, DEC IRP Report at 346, DEP IRP Report at 340.

A69. I recommend that Duke update the model to select up to 1,500 MW and up to 1,000 MW of two-hour batteries in DEP and DEC, respectively. These levels correspond to capacity values of 70%. Considering the cost discount that one can obtain from shorter-duration batteries, the tradeoff for capacity value may be selected in the model's optimization routines.

E. Duke's Operational Assumptions for Solar Should be Improved

Q70. WHAT ARE THE TWO MOST COMMON TYPES OF GROUND-MOUNT SOLAR PV PROJECTS INSTALLED TODAY?

A70. The two most common types are fixed-tilt arrays and single-axis tracking arrays. Fixed-tilt arrays feature fixed solar panels that are typically tilted toward the southern horizon. The level of tilt depends on several factors, but typical installations in the Carolinas will have tilts in the 20-30 degree range to increase the total amount of energy produced over the year. Single-axis tracking arrays feature panels that are typically oriented flat in north-south rows that can turn east to west as the day progresses. This tracking enables the panels to face the sun more directly through the day, increasing the amount and duration of energy production.

Q71. WHAT TRENDS EXIST IN THE LARGE-SCALE SOLAR MARKET RELATED TO FIXED-TILT OR TRACKING SYSTEMS?

A71. Over the past decade, there has been a steady shift from fixed-tilt projects to single-axis trackers that has corresponded to a decrease in the price premium of tracking system hardware.[84] Under today's economics, the benefit from added production outweighs the higher cost of tracking hardware, making it an economic decision to install trackers in most locations.

Q72. HAS THIS SAME TREND OCCURRED IN THE CAROLINAS?

A72. Yes, it has. Figure 7 below shows the share of PV systems install by type in North Carolina and South Carolina.[85] There has been a notable increase in tracker deployment since the mid-2010s. More than 80% of PV capacity completed in 2019 used single-axis or dual-axis

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[84] EIA Form 860, available at https://www.eia.gov/electricity/data/eia860/.

[85] *Id.*

trackers. Based on conversations with our solar industry members, there is every expectation that this growth trend will continue and that single-axis trackers will be remain the dominant type of system installed in the future.

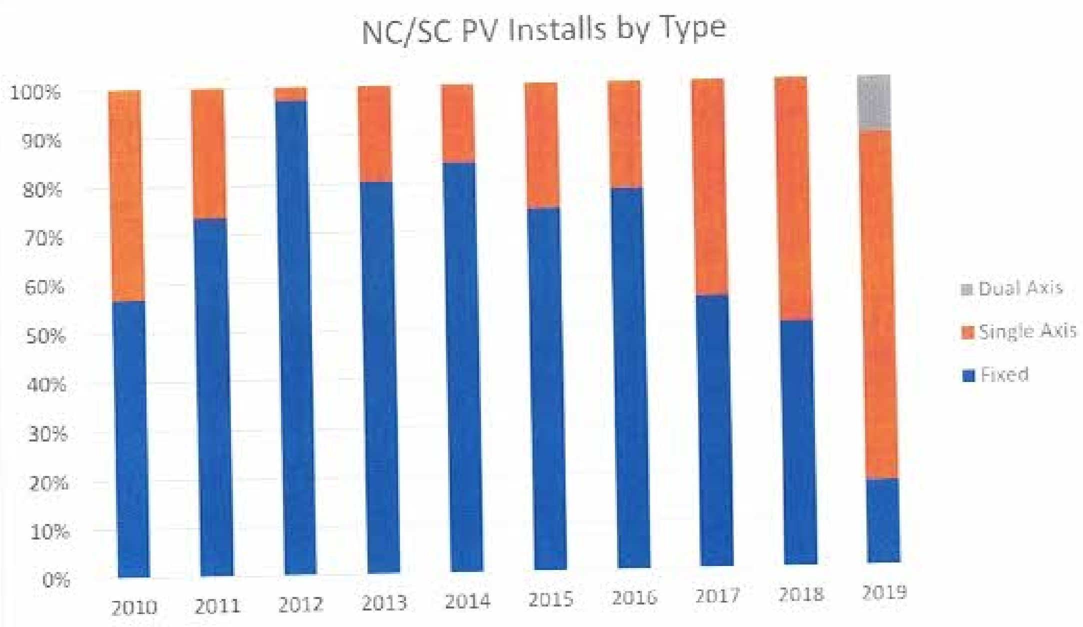

Figure 7 - NC/SC PV Installs by Type

Q73. IS THERE A DIFFERENCE IN SOLAR PRODUCTION FROM FIXED-TILT AND SINGLE-AXIS TRACKING SYSTEMS?

A73. Yes, and the difference is notable. In general, single-axis tracking systems climb to their peak output earlier in the morning and maintain their generation levels later in the afternoon, resulting in a sizable production premium over fixed-tilt systems. Single-axis tracking systems' ability to maintain production later in the afternoon increases the capacity value compared to fixed-tilt installations. Figure 8 below is taken from Astrapé Consulting's "Duke Energy Progress 2020 Resource Adequacy Study" and shows the difference between fixed-tilt and tracking systems at different inverter load rating ("ILR") assumptions.[86,87] The incremental generation in the morning and the evening adds over the year, resulting in tracking systems producing 19% more energy in total than fixed-tilt systems.[88]

Figure 7. Average August Output for Different Inverter Loading Ratios

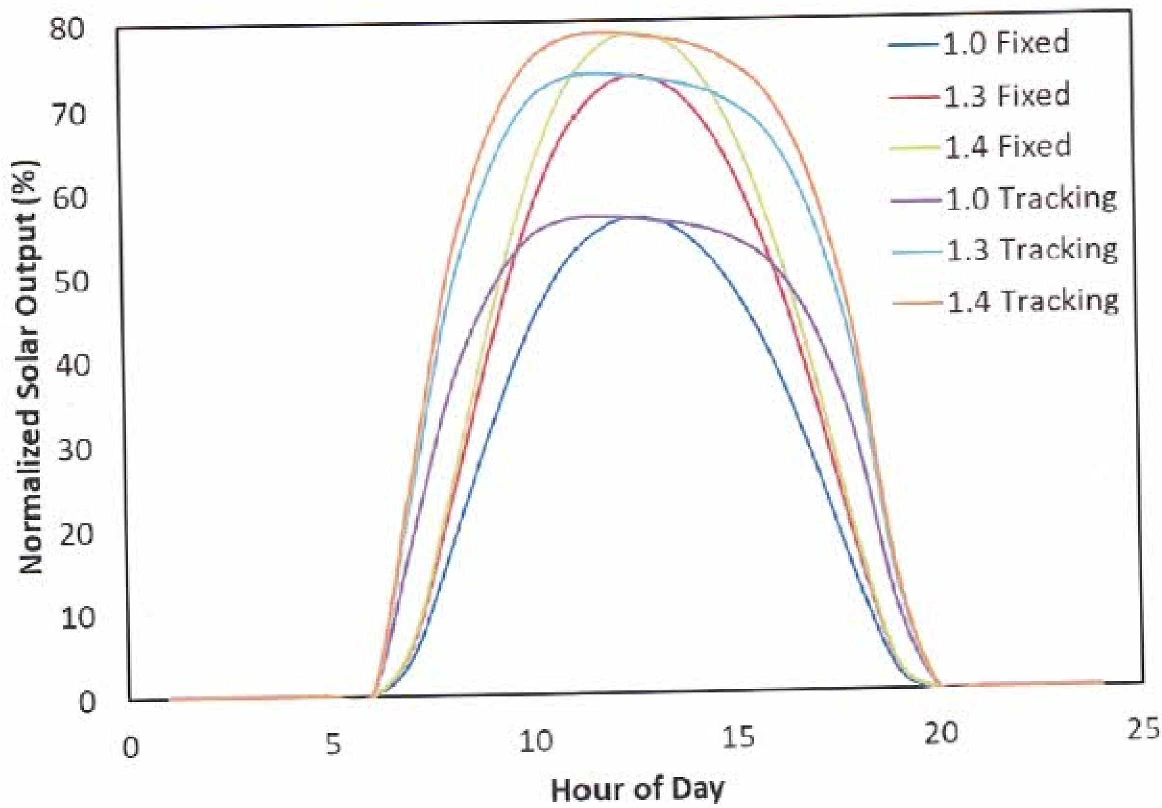

Figure 8 - Fixed vs. Tracking Generation Profile

Q74. PLEASE EXPLAIN HOW DUKE INCORPORATES SOLAR ASSUMPTIONS SUCH AS SYSTEM TYPE AND IRL INTO ITS IRP.

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[86] DEP 2020 Resource Adequacy Study at 35.

[87] The inverter load rating is the ratio of the DC capacity of the panels to the AC capacity of the inverter. While the PV system cannot exceed its AC capacity, increasing the ILR allows the system to produce at its maximum level for more hours, increasing total output.

[88] Exhibit KL-9, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 7-7).

A74. Duke's methodology of incorporating solar in its IRP is anything but straightforward. It relies on a 2018 report from Astrapé Consulting ("2018 Astrapé") to establish the solar-only capacity credit at different levels of penetration.[89] Astrapé modeled different tranches of solar deployment with different system type and ILR assumptions. From this, it estimated the summer and winter capacity credits of 20% and 1%, respectively.[90] These values were used in the IRP modeling for standalone solar projects.

Astrapé assumed 2,950 MW of existing plus "transitional" PV projects in its baseline forecast.[91] Of this nearly 3 GW of capacity, only 297 MW was assumed to be single-axis tracking, with the remainder fixed-tilt. It then added four tranches of capacity in DEP and DEC, assuming 75% was fixed-tilt and 25% single-axis tracking. At the end of its projected deployment, Astrapé assumed that of the 7 GW of solar deployed, only 1,120 MW or 16% would be single-axis trackers as shown in Figure 9 below.

[89] Exhibit KL-10, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-8 ("Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study")).

[90] The "capacity credit" is the fraction of solar nameplate capacity that is assumed to be available to meet summer and winter peak demands. Exhibit KL-10, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-8).

[91] Transitional projects are not defined in the Astrapé study, but appear to be similar to Duke's "designated" capacity.

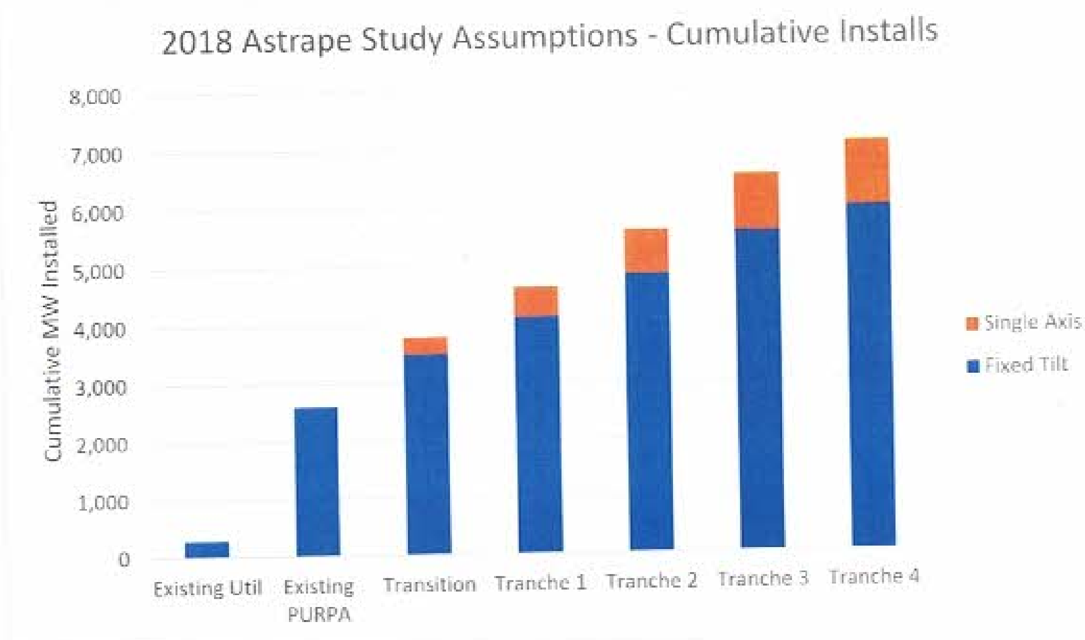

Figure 9 - 2018 Astrapé Study Assumptions - Cumulative Installs

By comparison, 5.2 GW of large-scale solar had been deployed in North Carolina and South Carolina through 2019.[92] At that point, single- and dual-axis trackers already comprised 40% of installed capacity, and based on recent trends, will be projected to increase further in the future. Figure 10 below shows the cumulative installation by type through 2019.

[92] Based on data reported to EIA Form 860 in 2019.

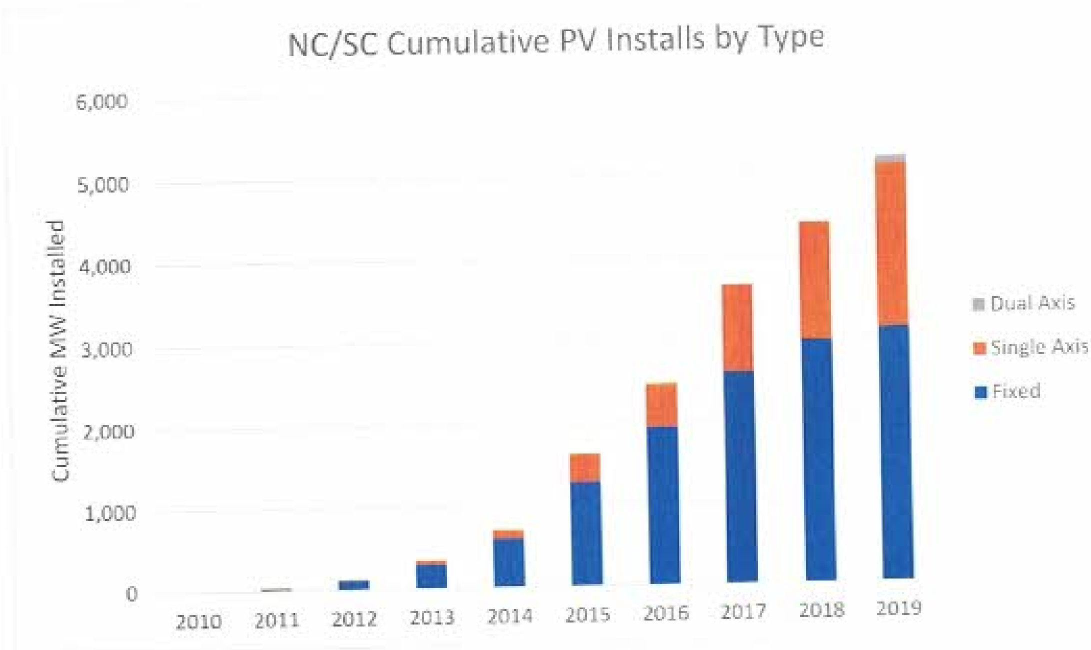

Figure 10 - NC/SC Cumulative PV Installs by Type

Q75. WHY IS THIS DISCREPANCY IMPORTANT?

A75. It is important because by underestimating the share of single-axis trackers, Astrapé is underestimating solar's capacity contribution. Its analysis shows that single-axis tracking systems provide substantially more winter capacity than fixed-tilt systems; tracking systems provided 4-5 times the winter capacity benefit as fixed tilt in DEC's territory, and 8-9 times the capacity benefit in DEP's territory.[93] Although the relative level of solar winter capacity contribution is small under Astrapé's assumptions, when deployed over many thousands of MW, it produces a meaningful difference in the winter capacity contribution of solar-only resources.

Further, because daily generation of single-axis trackers exceeds fixed-tilt systems, solar systems paired with storage will have more opportunity to charge their battery during winter months. This can increase the amount of stored energy that is available to meet both

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[93] 2018 Astrapé at 39-41.

morning and evening winter peaks, further increasing the capacity value of solar and storage systems.

Q76. DID DUKE USE THE SAME CAPACITY CONTRIBUTION ASSUMPTIONS FOR ITS STANDALONE SOLAR PROJECTS AS IT DID FOR ITS SOLAR PLUS STORAGE PROJECTS?

A76. No. While the standalone solar capacity contribution came from a 2018 Astrapé Consulting report, the storage and solar plus storage capacity contribution came from a 2020 Astrapé Consulting ELCC study.[94] In this report, Astrapé modeled new solar plus storage systems as single-axis trackers with a 1.5 ILR, but it is unclear what assumptions it used for the existing fleet of standalone solar.[95] The assumption that all new systems be trackers with high ILR is appropriate, but if Astrapé assumed an existing fleet mix that contained too few tracking systems, it could suffer the same underestimate in solar contribution as the 2018 study.

Q77. DOES DUKE USE THE SAME SYSTEM MIX ASSUMPTIONS IN ITS IRP AS IT DOES IN ITS CAPACITY CONTRIBUTION STUDIES?

A77. No. After establishing the capacity contribution of standalone solar from the 2018 Astrapé study, and solar plus storage and standalone storage from the 2020 ELCC study, Duke creates another set of assumptions for the deployment of solar going forward. The Company assumes that 100% of existing PURPA projects are fixed-tilt and will be replaced with fixed-tilt systems.[96] It assumes that development to meet "designated" and "mandated" demand (e.g. builds from existing programs such as CPRE and GSA) will be split 60/40 between single-axis trackers and fixed tilt systems.[97] Finally, Duke assumes future "undesignated" builds will be optimized based on modeling runs.

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[94] *Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study*, Astrapé Consulting, September 2020. ("ELCC Study")
[95] ELCC Study at 7.
[96] Exhibit KL-11, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-5).
[97] Exhibit KL-11.

Q78. WHAT IS THE BASIS FOR THESE FIGURES?

A78. The designation of 100% of PURPA projects as fixed-tilt appear to be based on a simple assumption: "This segment represents the existing capacity associated with standard PURPA contracts which are assumed to be fixed tilt configurations."[98] Duke did not provide any data to support this choice.

The decision to model "designated" and "mandated" system mix was based on the winning bids of the CPRE Tranche 1 RFP, which were received during summer 2018. While these bids may have been reflective of the state of the market at that time, they are no longer reflective of where the industry has moved.

The modeling optimization adds single-axis tracking systems over fixed-tilt systems for all the reasons that were discussed previously.

Q79. ARE DUKE'S ASSUMPTIONS ON THESE ELEMENTS VALID?

A79. No. Duke appears to have blanketly assumed that 100% of PURPA projects are current fixed-tilt and will all be replaced with fixed-tilt systems in the future. This assumption is clearly contradicted by the data. Figure 11 below shows the evolving mix of small systems in the Carolinas that are most likely to have been built under PURPA. While Duke's assumption that all PURPA projects are fixed-tilt may have been more valid through 2016, in the past five years the market has evolved and even these smaller projects are shifting to single-axis trackers. Of the 243 MW of systems under 10 MW built in 2019, a full 80% were single- or dual-axis trackers.

[98] Exhibit KL-11.

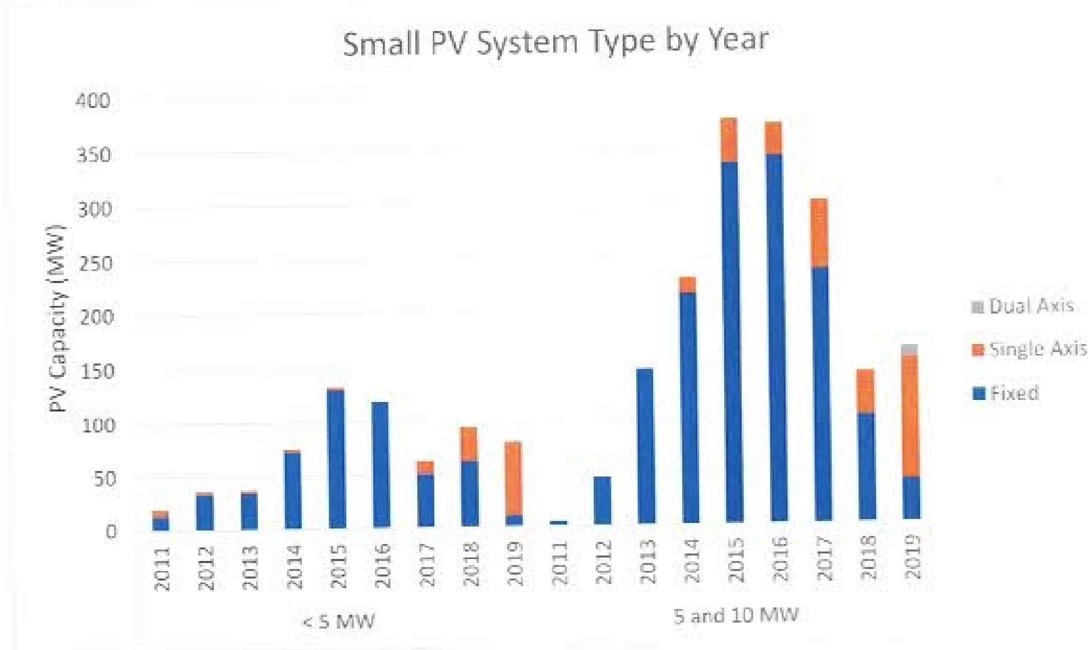

Figure 11 - Small PV System Type by Year

Q80. HAS A SIMILAR EVOLUTION OCCURRED FOR LARGER PROJECTS?

A80. Yes. Figure 12 below shows a similar chart for systems between 20 and 50 MW and over 50 MW. These are the projects that are winning CPRE bids; Duke noted that the median proposal for Tranche 2 RFP was 50 MW in DEC and 75 MW in DEP, with winning bids averaging 55.8 MW in DEC and 80 MW in DEP.[99] Duke's assumption that 40% of these systems will be fixed-tilt is out of date. In 2019, fixed-tilt systems only constituted 15% of capacity in these size categories. Based on trends across the country and in the Carolinas, there can be little expectation that the trend towards tracking systems will be reversed.

[99] Duke IRP Attachment II – Competitive Procurement of Renewable Energy Program Update at 7-8.

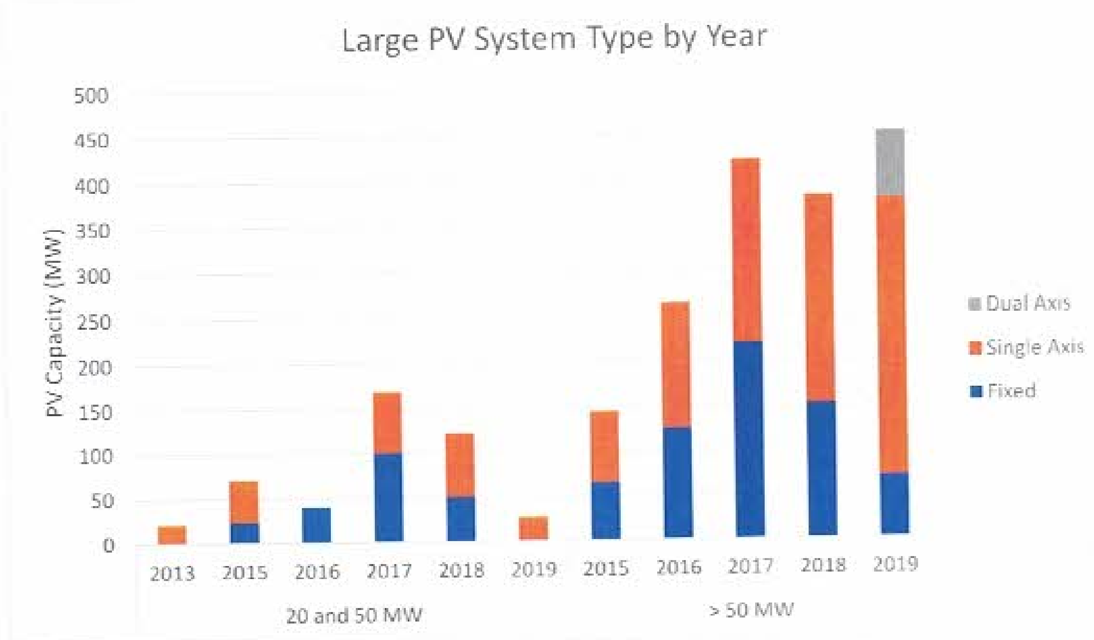

Figure 12 - Large PV System Type by Year

Q81. HOW MUCH CAPACITY IS IMPACTED BY THESE ASSUMPTIONS?

A81. The system type assumptions affect a substantial amount of solar capacity. Figure 13 below shows the breakdown of solar additions by program. The PURPA/NC REPS category (assumed to be 100% fixed-tilt) dominates the early mix, with CPRE capacity additions (assumed to be 60% tracker 40% fixed-tilt) growing through 2026. Only towards the end of 2029 does the future growth category (100% tracker) get deployed in earnest.

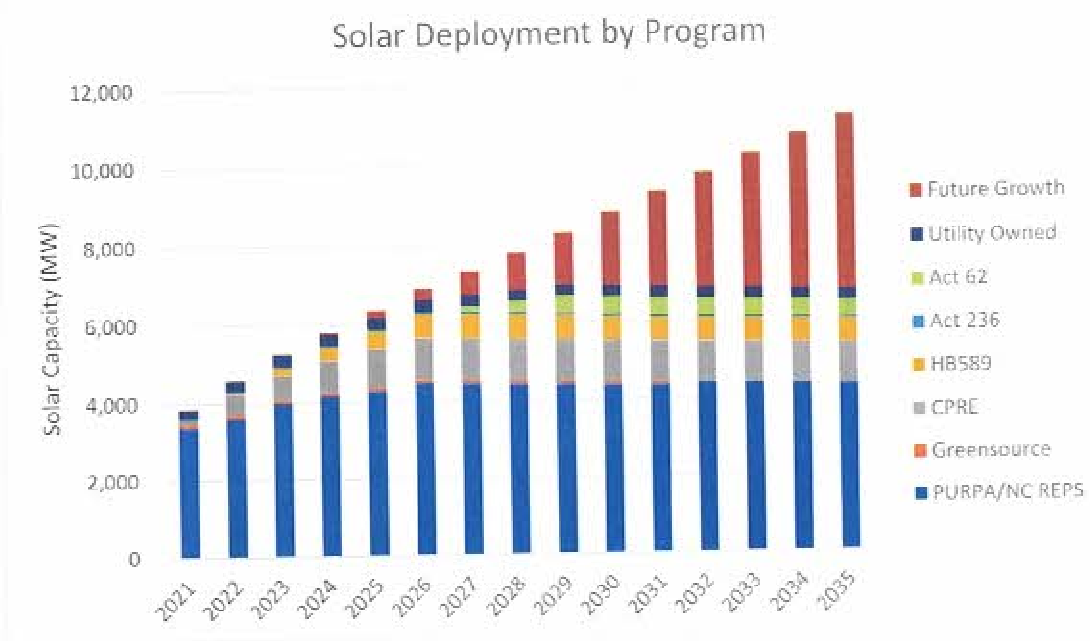

Figure 13 - Solar Deployment by Program

Duke's assumptions on system mix produce a model that relies too heavily on fixed-tilt systems and does not reward the multiple benefits of single-axis tracking systems that are being deployed in the market. This in turn negatively affects the economics of solar and solar plus storage facilities in the Company's modeling.

Q82. WHAT LIMITATIONS DID DUKE ASSUME IN ITS IRP RELATED TO THE INTERCONNECTION OF SOLAR AND SOLAR PLUS STORAGE PROJECTS?

A82. Duke placed a hard limit on the quantity of solar and solar plus storage that could be interconnected in any year to 500 MW (split 300 MW in DEC and 200 MW in DEP) in the base cases and 900 MW (split 500 MW in DEC and 400 MW in DEP) in the high renewable cases.[100] This limit affected all solar, not just those added through the modeling optimization.

Q83. HAS DUKE INTERCONNECTED MORE THAN 500 MW IN ANY YEAR IN IN THE PAST?

[100] Exhibit KL-12, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-18).

A83. Yes. Duke interconnected 718 MW and 744 MW in the two territories in 2015 and 2017, respectively. Its highest single year in DEC was 190 MW in 2016 and its highest year in DEP was 633 MW in 2017.[101]

Q84. WOULD YOU EXPECT DUKE TO BE MORE EFFICIENT AT INTERCONNECTING SYSTEMS NOW AND IN THE FUTURE THAN IT WAS IN 2015-2017?

A84. I would certainly hope so. Duke's IRP scenarios contemplate major build-outs of renewable energy and energy storage. To meet its 2050 net zero goals, the rate must accelerate even further. It is imperative that Duke continue to pursue all options to increase its interconnection capacity for new renewable projects. In addition, Duke's history with interconnection of solar facilities involved large numbers of smaller individual projects. Given the growing trend toward a smaller number of larger projects, Duke's interconnection capability should increase significantly.

Q85. WHAT DO YOU RECOMMEND WITH REGARD TO DUKE'S SOLAR ASSUMPTIONS?

A85. I recommend that Duke update several of its assumptions related to system mix. It is clearly not the case that 100% of PURPA projects are currently, or will be always in the future, fixed-tilt. Duke should perform an analysis on its current PURPA fleet to determine the actual mix of fixed-tilt and single-axis tracking projects and use these in its baseline assumptions. If, for some reason, it is unable to obtain these figures, Duke should utilize the latest data from EIA Form 860. It should further adjust its assumptions on replacement of these projects by recognizing the shift towards tracking that is occurring even at the small system sizes. I recommend an assumption that at least 80% of new PURPA projects be assumed as single-axis tracking based on an extrapolation of 2019 data and that Duke incorporate this into its assumption of replacement capacity from existing PURPA projects.

[101] Exhibit KL-12, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-18, attachment NCSEA_E-100_Sub165_DR2-18A.xlsx).